

Appendix D

SYSTEM SAFETY AND RISK OF UPSET TECHNICAL REPORT

Appendix D

System Safety and Risk of Upset

Appendix D presents the potential risks to the public from the proposed 24-inch diameter, 11.0 mile long natural gas pipeline and ancillary facilities. These risks would primarily result from unintentional releases of natural gas and the possibility of subsequent fires and/or explosions.

1.0 ENVIRONMENTAL SETTING

1.1 NATURAL GAS RISKS

Unintentional releases of natural gas from the existing pipeline or the above ground facilities could pose risks to human health and safety. For example, natural gas could be released from a leak or rupture in one of the pipe segments. If the natural gas was to reach a combustible mixture and an ignition source was present, a fire and/or explosion could occur, resulting in possible injuries and/or deaths.

1.2 NATURAL GAS CHARACTERISTICS

Natural gas is comprised primarily of methane. It is colorless, odorless, and tasteless. Methane is not toxic, but is classified as a simple asphyxiate, possessing a slight inhalation hazard. If breathed in high concentration, oxygen deficiency can result in serious injury or death.

Methane has an ignition temperature of 1,000°F and is flammable at concentrations between 5 percent and 15 percent in air. Unconfined mixtures of methane in air are not explosive. However, a flammable concentration within an enclosed space in the presence of an ignition source can explode. Methane is buoyant at atmospheric temperatures and disperses rapidly in air.

2.0 REGULATORY SETTING

2.1 FEDERAL

The United DOT provides oversight for the nation's natural gas pipeline transportation system. Its responsibilities are promulgated under Title 49, United States Code (USC) Chapter 601. The Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS), administers the national regulatory program to ensure the safe transportation of gas and other hazardous materials by pipeline.

2.1.1 Regulatory Framework

Two statutes provide the framework for the Federal pipeline safety program. The Natural Gas Pipeline Safety Act of 1968 as amended (NGPSA) authorizes the DOT to regulate pipeline transportation of natural (flammable, toxic, or corrosive) gas and other gases as well as the transportation and storage of liquefied natural gas (LNG). Similarly, the Hazardous Liquid Pipeline Safety Act of 1979 as amended (HLPESA) authorizes the DOT to regulate pipeline transportation of hazardous liquids (crude oil, petroleum products, anhydrous ammonia, and carbon dioxide). Both of these Acts have been recodified as 49 USC Chapter 601.

The OPS shares portions of this responsibility with state agency partners and others at the Federal, state, and local level. The State of California is certified under 49 USC Subtitle VIII, Chapter 601, §60105. The State has the authority to regulate intrastate natural and other gas pipeline facilities. The California Public Utilities Commission (CPUC) is the agency authorized to oversee intrastate gas pipeline facilities, including those proposed by the Applicant. (The California State Fire Marshal has jurisdiction for hazardous liquid pipelines.)

2.1.2 Pipeline Regulations

The Federal pipeline regulations are published in Title 49 of the Code of Federal Regulations (CFR), Parts 190 through 199. 49 CFR 192 specifically addresses natural and other gas pipelines. Many of these pipeline regulations are written as performance standards. These regulations set the level of safety to be attained and allow the pipeline operator to use various technologies to achieve the desired result.

The proposed 24-inch diameter transmission pipeline and ancillary facilities would all be designed, constructed, operated, and maintained in accordance with 49 CFR 192. Since these are intrastate facilities, the CPUC would have the responsibility for

enforcing the Federal and State requirements. 49 CFR 192 is comprised of 15 subparts, which are summarized below:

- Subpart A, General – This subpart provides definitions, a description of the class locations used within the regulations, documents incorporated into the regulation by reference, conversion of service requirements, and other items of a general nature.
- Subpart B, Materials – This subpart provides the requirements for the selection and qualification of pipe and other pipeline components. Generally, it covers the manufacture, marking, and transportation of steel, plastic, and copper pipe used in gas pipelines and distribution systems.
- Subpart C, Pipe Design – This subpart covers the design (primarily minimum wall thickness determination) for steel, plastic, and copper pipe.
- Subpart D, Design of Pipeline Components – This subpart provides the minimum requirements for the design and qualification of various components (e.g. valves, flanges, fittings, passage of internal inspection devices, taps, fabricated components, branch connections, extruded outlets, supports and anchors, compressor stations, vaults, overpressure protection, pressure regulators and relief devices, instrumentation and controls, etc.
- Subpart E, Welding of Steel Pipelines – This subpart provides the minimum requirements for welding procedures, welder qualification, inspection and repair/replacement of welds in steel pipeline systems.
- Subpart F, Joining of Materials Other Than By Welding – This subpart covers the requirements for joining, personnel and procedure qualification, and inspection of cast iron, ductile iron, copper, and plastic pipe joints.
- Subpart G, General Construction Requirements for Transmission Lines and Mains – This subpart provides the minimum construction requirements, including, but not limited to: inspection of materials, pipe repairs, bends and elbows, protection from hazards, installation in the ditch, installation in casings, underground clearances from other substructures, and minimum depth of cover.
- Subpart H, Customer Meters, Service Regulators and Service Lines – This subpart prescribes the minimum requirements for these components.
- Subpart I, Requirements for Corrosion Control – This subpart provides the minimum requirements for cathodic protection systems, required inspections and monitoring, remedial measures, and records maintenance.
- Subpart J, Testing Requirements – This subpart prescribes the minimum leak and strength test requirements.
- Subpart K, Upgrading – This subpart provides the minimum requirements for increasing the maximum allowable operating pressure.
- Subpart L, Operations – This subpart prescribes the minimum requirements for pipeline operation, including: procedure manuals, change in class locations,

damage prevention programs, emergency plans, public awareness programs, failure investigations, maximum allowable operating pressures, odorization, tapping, and purging.

- Subpart M, Maintenance – This subpart prescribes the minimum requirements for pipeline maintenance, including: line patrols, leakage surveys, line markers, record keeping, repair procedures and testing, compressor station pressure relief device inspection and testing, compressor station storage of combustible materials, compressor station gas detection, inspection and testing of pressure limiting and regulating devices, valve maintenance, prevention of ignition, etc.
- Subpart N, Qualification of Pipeline Personnel – This subpart prescribes the minimum requirements for operator qualification of individuals performing covered tasks on a pipeline facility.
- Subpart O, Pipeline Integrity Management – This subpart was promulgated on December 15, 2003. It requires operators to implement pipeline integrity management programs on the gas pipeline systems.

In general, the requirements of the Federal regulations become more stringent as the human population density increases. To this end, 49 CFR 192 defines area classifications, based on population density in the vicinity of a pipeline and specifies more rigorous safety requirements for more heavily populated areas. The class location is an area that extends 220 yards on either side of the centerline of any continuous 1-mile length of pipeline. The four area classifications are defined as follows:

- Class 1 - Location with 10 or fewer buildings intended for human occupancy.
- Class 2 - Location with more than 10 but less than 46 buildings intended for human occupancy.
- Class 3 - Location with 46 or more buildings intended for human occupancy or where the pipeline lies within 100 yards of a building, or small well-defined outside area pipeline any occupied by 20 or more people on at least 5 days a week for 10 weeks in any 12-month.
- Class 4 - Location where buildings with four or more stories aboveground are prevalent.

Pipeline facilities located within class locations representing more populated areas are required to have a more conservative design. For example, pipelines constructed on land in Class 1 locations must be installed with a minimum depth of cover of 30 inches in normal soil and 18 inches in consolidated rock. Class 2, 3, and 4 locations, as well as drainage ditches of public roads and railroad crossings, require a minimum cover of 36 inches in normal soil and 24 inches in consolidated rock. All pipelines installed in navigable rivers, streams, and harbors must have a minimum cover of 48 inches in soil or 24 inches in consolidated rock.

Class locations also specify the maximum distance to a sectionalizing block valve (e.g., 10.0 miles in Class 1, 7.5 miles in Class 2, 4.0 miles in Class 3, and 2.5 miles in Class 4 locations). Pipe wall thickness and pipeline design pressures, hydrostatic test pressures, maximum allowable operating pressure, inspection and testing of welds, and frequency of pipeline patrols and leak surveys must also conform to higher standards in more populated areas.

The proposed pipeline facilities would be constructed within a Class 1, 2, and 3 locations (PG&E 2007). Although an increase in population density adjacent to the right-of-way is not anticipated (see Section 4.11, Land Use and Planning), the Applicant would be required to demonstrate compliance with the more stringent requirements, reduce the maximum allowable operating pressure (MAOP) or replace the segment with pipe of sufficient grade and wall thickness to comply with 49 CFR 192 for the new class location if the population density should increase enough to change the Class location.

2.1.3 Pipeline Integrity Management

49 CFR 192 Subpart O, Pipeline Integrity Management grew out of a series of pipeline incidents with severe consequences. This Subpart requires operators of gas pipeline systems in High Consequence Areas (HCA's) to significantly increase their minimum required maintenance and inspection efforts. For example, all lines located within HCA's must be analyzed by conducting a baseline risk assessment. In general, the integrity of the lines must also be evaluated using an internal inspection device or a direct assessment, as prescribed in the regulation. Two incidents in particular, raised public concern regarding pipeline safety and necessitated these relatively new requirements.

Bellingham, Washington, June 10, 1999

According to the National Transportation Safety Board (NTSB) accident report, “about 3:28 p.m., Pacific daylight time, on June 10, 1999, a 16-inch diameter steel pipeline owned by Olympic Pipe Line Company ruptured and released about 237,000 gallons of gasoline into a creek that flowed through Whatcom Falls Park in Bellingham, Washington. About one and one half hours after the rupture, the gasoline ignited and burned approximately one and one half miles along the creek. Two 10-year-old boys and an 18-year-old young man died as a result of the accident. Eight additional injuries were documented. A single-family residence and the City of Bellingham's water treatment plant were severely damaged. As of January 2002, Olympic estimated that total property damages were at least \$45 million.

The major safety issues identified during this investigation are excavations performed by IMCO General Construction, Inc., in the vicinity of Olympic's pipeline during a major construction project and the adequacy of Olympic Pipe Line Company's inspections thereof; the adequacy of Olympic Pipe Line Company's interpretation of the results of in-line inspections of its pipeline and its evaluation of all pipeline data available to it to effectively manage system integrity; the adequacy of Olympic Pipe Line Company's management of the construction and commissioning of the Bayview products terminal; the performance and security of Olympic Pipe Line Company's supervisory control and data acquisition system; and the adequacy of Federal regulations regarding the testing of relief valves used in the protection of pipeline systems." (NTSB 2002)

Carlsbad, New Mexico, August 19, 2000

Per the NTSB accident report, "At 5:26 a.m., mountain daylight time, on Saturday, August 19, 2000, a 30-inch diameter natural gas transmission pipeline operated by El Paso Natural Gas Company ruptured adjacent to the Pecos River near Carlsbad, New Mexico. The released gas ignited and burned for 55 minutes. 12 persons who were camping under a concrete-decked steel bridge that supported the pipeline across the river were killed and their three vehicles destroyed. Two nearby steel suspension bridges for gas pipelines crossing the river were extensively damaged. According to El Paso Natural Gas Company, property and other damages or losses totaled \$998,296.

The major safety issues identified in this investigation are the design and construction of the pipeline, the adequacy of El Paso Natural Gas Company's internal corrosion control program, the adequacy of Federal safety regulations for natural gas pipelines, and the adequacy of Federal oversight of the pipeline operator." (NTSB 2003)

Pipeline Integrity Management Regulations

As noted earlier, 49 CFR 192, Subpart O, Pipeline Integrity Management, is relatively new and was developed in response to the two major pipeline incidents discussed above. In 2002, Congress passed an Act to strengthen the pipeline safety laws. The Pipeline Safety Improvement Act of 2002 (HR 3609) was passed by Congress on November 15, 2002, and was signed into law by the President in December 2002. As of December 17, 2004, gas transmission operators of pipelines in high consequence areas (HCA's) were required to develop and follow a written integrity management program that contained all of the elements prescribed in 49 CFR 192.911 and addressed the risks on each covered transmission pipeline segment.

The DOT (68 Federal Register 69778, 69 Federal Register 18228, and 69 Federal Register 29903) defines HCA's as they relate to the different class zones, potential impact circles, or areas containing an identified site as defined in 49 CFR 192.903. The OPS published a series of rules from August 6, 2002 to May 26, 2004 (69 Federal Register 69817 and 29904) that define HCA's where a gas pipeline accident could do considerable harm to people and their property. This definition satisfies, in part, the Congressional mandate in 49 USC 60109 for the OPS to prescribe standards that establish criteria for identifying each gas pipeline facility in a high-density population area.

The HCA's may be defined in one of two ways. Both methods are prescribed by 49 CFR 192.903. The first includes:

- Current Class 3 and 4 locations;
- Any area in Class 1 or 2 locations where the potential impact radius is greater than 660 feet (200 meters) and the area within a potential impact circle contains 20 or more buildings intended for human occupancy; or
- Any area in Class 1 or 2 locations where the potential impact circle includes an "identified site."

In the second method, an HCA includes any area within a potential impact circle that contains:

- 20 or more buildings intended for human occupancy; or
- an "identified site."

"Identified sites" include areas such as beaches, playgrounds, recreational facilities, camp grounds, outdoor theaters, stadiums, recreational areas, religious facilities, and other areas where high concentrations of the public may gather periodically as defined by 49 CFR 192.903.

The "potential impact radius" is calculated as the product of 0.69 and the square root of the maximum allowable operating pressure of the pipeline (in psig), multiplied by the pipeline diameter (in inches) squared. ($R = 0.69 * (MAOP * d^2)^{0.5}$)

The potential impact circle is a circle with a radius equal to the potential impact radius.

Once a pipeline operator has identified the HCA's along its pipeline(s), it must apply the elements of its integrity management program to those segments of the pipeline within the HCA's. The pipeline integrity management rule for HCA's requires inspection of the entire pipeline within HCA's every 7 years.

As noted earlier, the proposed pipeline facilities are located within a Class 1, 2 and 3 areas. As a result, using the first HCA definition, the portions of the line within Class 3 areas would be within an HCA. (The impact radius is 440-feet, using the 24-inch pipe diameter and an MAOP of 720 psig.) Using the second HCA definition, the portion of the pipeline nearest the existing apartments (Station 525+00) would be located within an HCA. As a result, certain portions of the Project will be required to be included in the Applicant's Pipeline Integrity Management Plan. Should the population density increase, additional portions of the pipeline may become located within an HCA; should this occur, the Applicant would be required by Federal regulation to include the affected pipe segments in their Pipeline Integrity Management Plan.

2.2 STATE

As noted earlier, these intrastate pipeline facilities would be under the jurisdiction of the CPUC, as a result of their certification by the OPS. (The State of California is certified under 49 USC Subtitle VIII, Chapter 601, §60105.) The State requirements for designing, constructing, testing, operating, and maintaining gas piping systems are stated in CPUC General Order Number 112. These rules incorporate the Federal regulations by reference, but for natural gas pipelines, they do not impose any additional requirements affecting public safety.

3.0 SIGNIFICANCE CRITERIA

3.1 INDIVIDUAL RISK

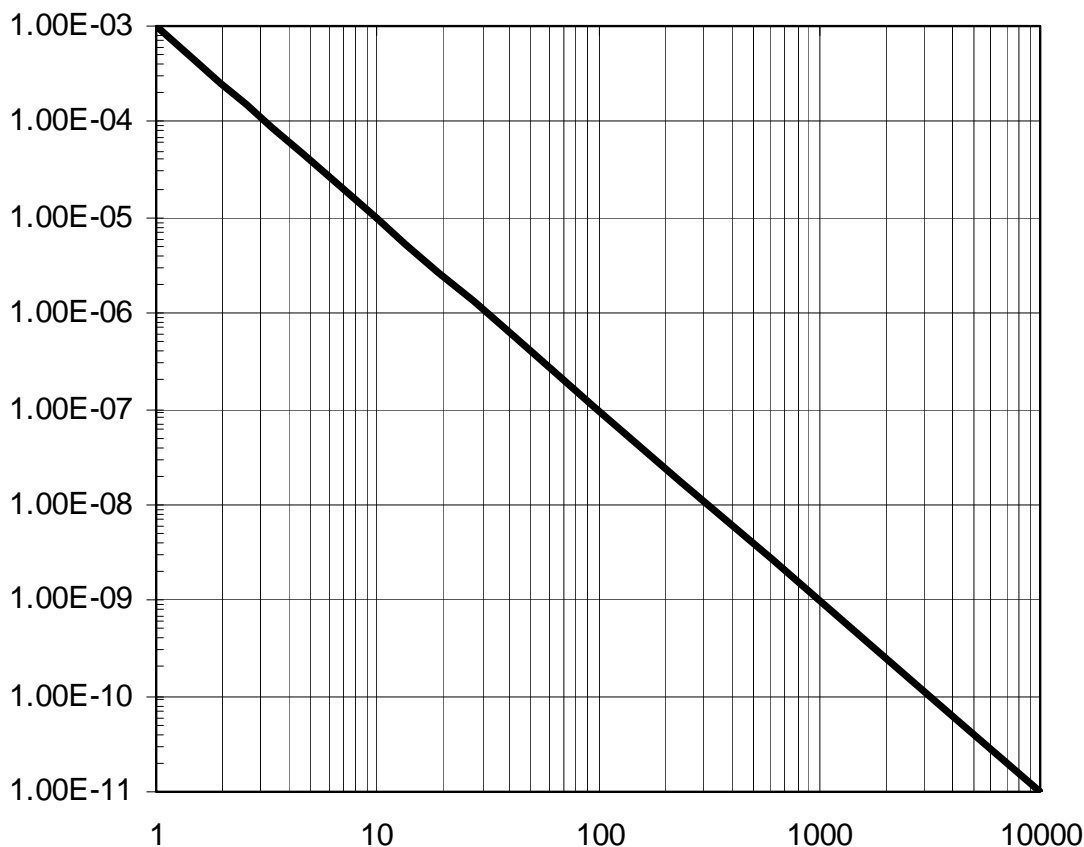
For individual fatality risks, the generally accepted significance criterion is an annual likelihood of 1 in one million (1:1,000,000) (CDE 2007, CPUC 2006).

3.2 SOCIETAL RISK

Societal risk is the probability that a specified number of people will be affected by a given event. The accepted number of casualties is relatively high for lower probability events and much lower for more probable events. However, the acceptable values for societal risk vary greatly by different agencies and jurisdictions. Unfortunately, there are no prescribed societal risk guidelines for the United States, nor the State of California. The United Kingdom, considers those events which result in 100 fatalities, with an annual probability of 1.0×10^{-5} (1:100,000) or less. The Committee for the Prevention of Disasters, uses the criteria as shown in Figure 3.2-1 below. This data is the same as the criteria used in the Netherlands and is the most conservative of the published data

for Western Europe. These criteria have been used to evaluate societal risk in this report.

Figure 3.2-1: Societal Risk Criteria



Source: Committee for the Prevention of Disasters, The Hague

4.0 IMPACT ANALYSIS AND MITIGATION

4.1 POTENTIAL IMPACTS

The proposed Project could pose additional risks to the public. Natural gas could be released from a leak or rupture. If the natural gas reached a combustible mixture and an ignition source was present, a fire and/or explosion could occur, resulting in possible injuries and/or deaths.

Impact HAZ-1: Injuries or Fatalities

An unintentional release from the proposed Project could result in injuries and/or deaths (Significant and Unavoidable, Class 1).

4.1.1 Impact Discussion

Fire

The physiological effect of fire to humans depends on the rate at which heat is transferred from the fire to the person, and the time the person is exposed to the fire. Skin that is in contact with flames can be seriously injured, even if the duration of the exposure is just a few seconds. Thus, a person wearing normal clothing is likely to receive serious burns to unprotected areas of the skin when directly exposed to the flames from a flash fire (vapor cloud fire).

Humans in the vicinity of a fire, but not in contact with the flames, would receive heat from the fire in the form of thermal radiation. Radiant heat flux decreases with increasing distance from a fire. So those close to the fire would receive thermal radiation at a higher rate than those farther away. The ability of a fire to cause skin burns due to radiant heating depends on the radiant heat flux to which the skin is exposed and the duration of the exposure. As a result, short-term exposure to high radiant heat flux levels can be injurious. But if an individual is far enough from the fire, the radiant heat flux would be lower, likely incapable of causing injury, regardless of the duration of the exposure.

An incident heat flux level of 1,600 Btu/ft²-hr is considered hazardous for people located outdoors and unprotected. Generally, humans located beyond this heat flux level would not be at risk to injury from thermal radiation resulting from a fire. The radiant heat flux effects to humans are summarized below:

- 8,000 Btu/hour-square foot (25.1 kW/m²) – 50% mortality (CDE 2007).
- 3,500 Btu/hour-square foot (11.0 kW/m²) - Second degree skin burns after ten seconds of exposure, 15% probability of fatality. This assumes that an individual is unprotected or unable to find shelter soon enough to avoid excessive exposure (Quest 2003). Other data sources provide a 10% mortality at 5,500 Btu/hour-square foot and 15% mortality at 5,800 Btu/hour-square foot (CDE 2007).
- 1,600 Btu/hour-square foot (5.0 kW/m²) - Second degree skin burns after thirty seconds of exposure.
- 440 Btu/hour-square foot (1.4 kW/m²) - Prolonged skin exposure causes no detrimental effect (CDE 2007, Quest 2003).

Explosion

As noted earlier, natural gas does not explode unless it is in a confined space within a specific range of mixtures with air and is ignited. However, if an explosion does occur, the physiological effects of overpressures depend on the peak overpressure that reaches a person. Exposure to overpressure levels can be fatal. People located outside the flammable cloud when a combustible mixture ignites would be exposed to lower overpressure levels than those inside the flammable cloud. If a person is far enough from the source of overpressure, the explosion overpressure level would be incapable of causing injuries. The generally accepted hazard level for those inside buildings is an explosion overpressure is 1.0 psig. This level of overpressure can result in injuries to humans inside buildings, primarily from flying debris. The consequences of various levels of overpressure are outlined in the table below.

Table 4.1.1-1 Explosion Over-Pressure Damage Thresholds

Side-On Over-Pressure	Damage Description
0.02 psig	Annoying Noise
0.03 psig	Occasional Breaking of Large Window Panes Under Strain
0.04 psig	Loud Noise; Sonic Boom Glass Failure
0.10 psig	Breakage of Small Windows Under Strain
0.20 psig	Glass Breakage - No Injury to Building Occupants
0.30 psig	Some Damage to House Ceilings, 10% Window Glass Broken
0.50 to 1.00 psig	Large and Small Windows Usually Shattered, Occasional Damage to Window Frames
0.70 psig	Minor Damage to House Structures, Injury, but Very Unlikely to Be Serious
1.00 psig	1% Probability of a Serious Injury or Fatality for Occupants in a Reinforced Concrete or Reinforced Masonry Building from Flying Glass and Debris 10% Probability of a Serious Injury or Fatality for Occupants in a Simple Frame, Unreinforced Building
2.30 psig	0% Mortality to Persons Inside Buildings or Persons Outdoors (CDE 2007)
3.10 psig	10% Mortality to Persons Inside Buildings (CDE 2007)
3.20 psig	<10% Mortality to Persons Outdoors (CDE 2007)
14.5 psig	1% Mortality to Those Outdoors (LEES)

Sources: LEES, CDE 2007, Quest 2003

4.1.2 Baseline Data

The anticipated frequency of unintentional releases by cause will be developed in this section. The frequencies will be based primarily on the 1981 through 1990 data collected for California's regulated interstate and intrastate hazardous liquid pipelines (Payne, 1993). This report included a complete inventory of all 7,800 miles of interstate and intrastate hazardous liquid pipelines within the State. It also included an audit of all 514 unintentional releases that occurred within this 10-year period. Based on a review of the national and international data available, using this California data is considered appropriate, for the following reasons:

- The California data is the only completely audited, recent, relatively large data sample available. A team of field technicians visited the operational sites of every regulated pipeline operator within the State. The team spent between one and five days at each site reviewing insurance records, unintentional release records, pipeline inventory data, drawings, internal incident reports, etc. and interviewing operator personnel. Using this approach allowed the team to collect data for very small releases, which were not reportable to the regulatory agencies.
- The pipelines included in the California study are representative of the proposed pipeline segment (e.g., similar diameter, variable terrain, all steel, etc.). Specifically, the length weighted mean pipe diameter of these lines was 12.3-inches, the lines were constructed of welded steel pipe, operated and maintained to similar regulatory requirements.
- The California data included a complete pipeline inventory and unintentional release data with many parameters. As a result, it allowed the authors to investigate the effects of various operational and design considerations (e.g., operating temperature, period of construction, etc.). The conclusions drawn from the California study are useful in assessing the risks associated with the proposed pipeline segment. The California study identified the effects of several pipeline parameters on the overall incident rates. Using these data facilitated the development of the anticipated frequency of unintentional releases from the proposed pipeline segment, using actual pipeline construction and operational conditions.
- The reader should note that the frequency of unintentional releases presented in the California study is higher than those reported by other sources. The higher frequency is due to the inclusion of all releases, regardless of spill volume or extent of property damage; these data include all releases, including those that were beneath the thresholds for agency reporting. Other sources only include releases meeting certain criteria; they typically only include DOT reportable releases.
- Since the California study included a complete pipeline inventory, including the actual length of pipe installed for each of several parameters (e.g., operating

temperature, external coating, type of steel, operating pipe stresses as a function of the specified minimum pipe stress, etc.), the data enabled a very comprehensive statistical analysis. Multinomial logit regressions were performed to evaluate the probability of pipeline unintentional releases considering each of these variables. Using these statistical results and other data, we have developed anticipated pipeline incident rates for this project.

Frequency of Unintentional Releases

In the following paragraphs, we will develop the anticipated unintentional release rate for this pipeline by cause.

External Corrosion

External corrosion of a buried pipe is an electro-chemical reaction, which can occur when bare (un-coated) steel is in contact with the earth. The moist soil surrounding a pipeline can serve as an electrolyte. When this occurs, the pipe can become an anode. The current then flows through the electrolyte, from the anode (pipe) to the cathode (soil). In this instance, the anode (pipe) loses material (corrodes) as this process occurs.

The intent of an effective external corrosion prevention program is twofold. First, the pipe is protected from corrosion by insulating it from contact with the electrolyte (moist soil) using an external coating. Second, in the event that the coating should fail, the pipe is prevented from becoming the anode by introducing some other material into the electrochemical chain that is more anodic than the pipe, or appears to be because of an impressed current. An impressed current or sacrificial anode cathodic protection system makes the current flow through the soil, toward the pipe, instead of away from it; thus, external corrosion is eliminated.

An impressed current system takes alternating current electrical power from a utility source or solar panels. A transformer is used to reduce the voltage. A rectifier then converts the alternating current to a direct current. The direct current flows to and through anodes (graphite, steel, or other material) and into the surrounding earth. At locations where there may be a break in the external pipe coating (holiday), the current will reach the pipeline. It will then flow along the line to the rectifier, completing the circuit, preventing external corrosion at the external pipe coating holiday.

External corrosion typically causes a relatively large percentage of unintentional releases. Often, these releases are relatively small in volume, with low release rates. However, they often can go unnoticed for long periods of time.

The California study found that the frequency of unintentional releases (of all volumes) caused by external corrosion was 4.18 unintentional releases per 1,000 mile-years. However, the external corrosion caused incident rate varied significantly by decade of pipe construction and pipeline operating temperature.

Effects of Decade of Construction on External Corrosion

The statistical analyses performed in the California study indicated that the decade of pipeline construction directly affected the incident rate. The reader should note that this figure included all spills, regardless of spill volume. The majority of these spills would not require DOT reporting. As a result, the reader should not attempt to directly compare these values. They can only be compared after the spill volume distribution has been considered.

During the 1940's and 1950's, significant improvements were made in pipeline construction techniques and improvements in materials. Relative to external corrosion, the primary improvements included advances in external coatings and more widespread use of these coatings and cathodic protection systems. These items account for the significant reduction in external corrosion incident rates for modern pipelines, versus pipelines constructed prior to the 1940's. For newer pipelines, it is impossible to isolate the individual affects of pipe age and other improvements (e.g. technology, construction techniques, the more widespread use of high quality external coatings and cathodic protection systems). The table below presents the California data by decade of pipeline construction by incident cause.

Table 4.1.2-1 Incident Rates by Decade of Construction

Incident Cause	Pre-1940	1940-49	1950-59	1960-69	1970-79	1980-89
External Corrosion	14.12	4.24	2.47	1.47	1.24	0.00
Internal Corrosion	0.38	0.27	0.10	0.16	0.00	0.28
3 rd Party - Construction	1.96	1.06	0.68	0.66	0.25	0.28
3 rd Party - Farm Equipment	0.53	1.33	0.05	0.00	0.00	0.00
3 rd Party - Train Derailment	0.00	0.00	0.00	0.05	0.25	0.00
3 rd Party - External Corrosion	0.45	0.00	0.10	0.33	0.00	0.00
3 rd Party - Other	0.30	0.13	0.05	0.05	0.00	0.00
Human Operating Error	0.30	0.13	0.00	0.11	0.25	0.00
Design Flaw	0.08	0.00	0.00	0.00	0.00	0.14
Equipment Malfunction	0.38	0.53	0.10	0.60	1.24	0.00
Maintenance	0.00	0.00	0.24	0.00	0.00	0.00
Weld Failure	0.38	0.27	0.15	0.44	0.25	0.00
Other	0.83	0.13	0.24	0.27	0.25	0.28
Total	19.71	8.09	4.18	4.14	3.73	0.98

Source: Payne, 1993

Effects of Operating Temperature on External Corrosion

The statistical analyses performed in the California study indicated that operating temperature directly affected the frequency of unintentional releases. Considering all pipelines, regardless of decade of construction, those that were operated near ambient temperatures had an external corrosion caused incident rate of 1.33 unintentional releases per 1,000 mile-years. The incident rate rose dramatically as the operating temperature was increased.

The proposed pipeline segment will be operated at ambient temperatures. Table 4.5.4-3 indicates that the external corrosion incident rates for the California lines operated at various temperatures ranged from 0.48 to 11.36 unintentional releases per 1,000 mile-years. However, the lines operated between 130°F and 159°F had a 1947 mean year of pipeline construction; as discussed earlier, pipe age also significantly affected the incident rate. This effect is also reflected in these data.

Table 4.1.2-2 Incident Rates by Design Operating Temperature

Incident Cause	0-69°F	70-99°F	100-129°F	130-159°F	160°F+
External Corrosion	0.48	1.33	7.11	11.36	11.31
Internal Corrosion	0.00	0.21	0.32	0.57	0.08
3 rd Party - Construction	1.91	0.94	0.95	0.57	0.60
3 rd Party - Farm Equipment	0.00	0.30	0.47	0.00	0.08
3 rd Party - Train Derailment	0.00	0.04	0.00	0.00	0.00
3 rd Party - External Corrosion	0.00	0.06	0.16	0.00	0.15
3 rd Party - Other	0.00	0.24	0.16	0.00	0.15
Human Operating Error	0.00	0.11	0.00	0.00	0.23
Design Flaw	0.00	0.04	0.00	0.00	0.00
Equipment Malfunction	0.00	0.24	0.16	0.57	0.98
Maintenance	0.00	0.09	0.16	0.00	0.00
Weld Failure	0.00	0.19	0.32	0.00	0.60
Other	0.00	0.21	1.11	1.14	0.45
Total	2.39	4.00	10.92	14.21	14.63

Source: Payne, 1993

Applicant Proposed and Agency Required External Corrosion Mitigation Measures

To reduce the likelihood of releases caused by external corrosion, the following measures would be implemented by the Applicant:

- **Modern External Pipe Coating** - The proposed pipeline segment will be externally coated with a minimum of 16 mils (0.016-inches) of fusion-bonded epoxy (FBE) external coating. For pipe segments installed using the hammer bore and horizontal directional drilling (HDD) process, 30 mils (0.030-inches) of Powercrete coating will be installed over the FBE to protect the FBE during installation.
- **Impressed Current Cathodic Protection System** - The proposed pipeline will have an impressed current cathodic protection system. One new rectifier will be installed near the Twin Cities Road crossing.
- **Monitoring** - At least once each calendar year, at intervals not exceeding 15 months, the Applicant will be required to test their cathodic protection system in accordance with 49 CFR 192.465.
- **Visual Inspections** - Each time buried pipe is exposed for any reason, the Applicant will be required to examine the pipe for evidence of external corrosion in accordance with 49 CFR 192.459. If active corrosion is found, the operator is required to investigate and determine the extent. Pipeline operators are required to maintain records of these DOT required inspections. They are routinely reviewed by DOT staff during their inspections.

Anticipated External Corrosion Caused Incident Rate

Using the data presented in Tables above, as well as the Applicant's proposed mitigation measures, an opinion of the anticipated frequency of unintentional releases due to external corrosion from the proposed pipe segment has been developed. These segments will normally be operated at ambient temperatures, using externally coated pipe, with an impressed current cathodic protection system; the anticipated frequency of external corrosion caused unintentional releases will be approximately 1.0 unintentional releases per 1,000 mile-years. This frequency is intended to reflect the average value over a 50-year project life. During the early years of operation, the frequency of externally corrosion caused incidents will likely approach zero. It should also be noted that the statistical impact of the new USDOT pipeline integrity regulations are unknown at this time. But they will likely reduce the frequency of releases on the proposed pipeline components located within an HCA which will be included in a Pipeline Integrity Management Plan.

Internal Corrosion

49 CFR 192.475 and 477 outline the regulatory requirements for internal corrosion control and monitoring. Some of these requirements include:

- "Corrosive gas may not be transported by pipeline, unless the corrosive effect of the gas on the pipeline has been investigated and steps have been taken to minimize internal corrosion."
- "If corrosive gas is being transported, coupons or other suitable means must be used to determine the effectiveness of the steps taken to minimize internal corrosion. Each coupon or other means of monitoring internal corrosion must be checked two times each calendar year, but with intervals not exceeding 7½ months."
- "Whenever any pipe is removed from the pipeline for any reason, the internal surface must be inspected for evidence of corrosion...."

The Applicant has not proposed any mitigation measures, in addition to those required by applicable regulations.

The possibility of an internal corrosion/erosion caused unintentional release is low, but the possibility does exist. Using the California data, a frequency of 0.2 unintentional releases per 1,000 mile-years will be used for unintentional releases caused by internal corrosion. The proposed frequency is intended to reflect the average value over a 50-year project life. During the early years of operation, we would expect the frequency of these incidents to approach zero.

Third Party Damage

Like external corrosion, third party damage causes a large percentage of accidental pipeline releases. As noted earlier, 20 to 30 percent of the unintentional releases have reportedly been caused by third parties. The Applicant will be required to implement the following mitigation measures to reduce the frequency of third party caused releases.

- One-Call System – The applicant will subscribe to the USA North underground service alert “one-call” system. A toll free number is available for contractors and others to use before they begin excavations. Once a contractor calls and identifies its proposed excavation location, the organization will notify the Applicant and other underground facility owners in the vicinity. The owners respond to these calls with personal communications with the excavator. If their facilities are nearby, they mark the location of their facilities on the ground, so third party intrusions can be avoided. Participation in a one-call system is required as part of an operator's damage prevention program, per 49 CFR 192.614.
- Line Marking – The Applicant is required by federal regulation (49 CFR 192.707) to install line marker posts such that the pipeline is readily identifiable. In addition, they are required to have warning signs installed at each side of road, railroad, and waterway crossings, and at fence lines across open or agricultural property, crossings of other lines (e.g., irrigation, oil, gas, telephone, utilities) where practical, and where the line is above ground in areas accessible to the public.
- Right-of-Way Patrolling - 49 CFR 192.705 requires each operator to have a patrol program to monitor for indications of leaks, nearby construction activity, and any other factors that could affect safety and operation. The frequency of these inspections is based on a number of factors. For the proposed line, these patrols must be conducted at least twice each calendar year for road crossings and once each calendar year in other locations.
- Leakage Surveys – A leakage survey must be conducted at least once each calendar year.
- Public Education - 49 CFR 192.616 requires pipeline operators to develop and implement a written continuing public education program that follows the guidance provided in the American Petroleum Institute's (API's) Recommended Practice 1162 Public Awareness Programs for Pipeline Operators as their public education procedure.

The California study found that the overall frequency of third party damage caused unintentional releases was 1.46 unintentional releases per 1,000 mile-years. For pipelines constructed in the 1950's, the frequency was only 0.88 unintentional releases per 1,000 mile-years; it was even lower for newer lines. These lower values were primarily due to the increased awareness of the threat from third party damage to

pipeline facilities; newer lines have benefited from improved line marking, one-call dig alert systems, avoidance of high risk areas, improved documentation, increased depth of cover, and public awareness programs.

The frequency of third party damage caused unintentional releases for all volume releases from the existing line will be approximately 0.4 incidents per 1,000 mile-years.

Human Operating Error

49 CFR 192 provides specific requirements for pipeline operations and maintenance manuals and procedures. It also requires that all operations and maintenance personnel be adequately trained. Historically, human operator error has not been a major cause of pipeline unintentional releases.

The frequency of unintentional releases caused by human operating error will be approximately 0.1 unintentional releases per 1,000 mile-years.

Design Flaw

The estimated frequency of unintentional releases caused by design flaw/error will be 0.03 unintentional releases per 1,000 mile-years. Although these unintentional releases are rare, they do occur. Often, an unintentional release that is caused by a design flaw is categorized improperly. The designation of an unintentional release cause is often subjective. For example, should a pipeline be severed during a landslide, the operator may indicate that the cause was third party damage. However, it may have been a design error or oversight that placed the pipeline within the geo-hazard in the first place.

Equipment Malfunction

The frequency of equipment malfunction caused unintentional releases will be approximately 0.4 unintentional releases per 1,000 mile-years.

Maintenance

The pipeline will be maintained and operated in accordance with federal and state regulations. The frequency of improper maintenance caused unintentional releases will be approximately 0.07 unintentional releases per 1,000 mile-years.

Weld Failure

The Applicant has proposed that 100 percent of the full penetration circumferential welds will be inspected by radiography in accordance with American Petroleum Institute (API) Standard 1104.

The frequency of unintentional releases caused by weld failure will be approximately 0.3 unintentional releases per 1,000 mile-years.

Other or Unknown

Based on the California study, we estimate that the frequency of unintentional releases caused by other or unknown sources will be 0.5 unintentional releases per 1,000 mile-years.

Overall Likelihood of Unintentional Releases

Using the data described above, we expect that the frequency of unintentional releases for all releases, regardless of size/volume, will be 3.0 unintentional releases per 1,000 mile-years. As noted earlier, this is the anticipated average frequency of releases over the project 50-year life. During the early period of operation, the actual release rate will be far less than this value, increasing as the pipeline ages.

Frequency of Reportable Releases, Injuries, and Fatalities

In the following paragraphs, the frequency of impacts to humans will be estimated using data from the following sources:

- United States Natural Gas Transmission and Gathering Lines (U.S. Department of Transportation [USDOT]) – 1970 through 2006.
- United States Interstate Hazardous Liquid Pipelines (USDOT) - 1984 through 1998.
- California Regulated Interstate and Intrastate Hazardous Liquid Pipelines (Payne, 1993) - 1981 through 1990.

Each of these data sets provides pipeline incident data for reportable incidents. However, the criteria for reporting incidents differ for each source. This makes direct comparison of the individual results difficult. On the other hand, it provides a methodology for estimating incident rates for a variety of consequences.

U.S. Natural Gas Transmission Lines - 1970 to June 1984

Since the DOT natural gas pipeline reporting criteria changed in June 1984, the incident reports beginning in July 1984 have been summarized separately, in the next section of this document. The criteria for natural gas releases to be reported to the DOT from 1970 through June 1984 were as follows:

- Resulted in a death or injury requiring hospitalization;
- Required the removal from service of any segment of a transmission pipeline;
- Resulted in gas ignition;
- Caused an estimated damage to the property owner, or of others, or both, of \$5,000 or more;
- Involved a leak requiring immediate repair;
- Involved a test failure that occurred while testing either with gas or another test medium; or
- In the judgment of the operator, was significant even though it did not meet any of the above criteria.

The frequencies of the various consequences reported during this period are summarized below.

- Reportable Unintentional Releases - 1.3 incidents per 1,000 mile-years.
- Reportable Injuries - 0.096 injuries per 1,000 mile-years (0.007 public injuries per 1,000 mile-years).
- Fatalities - 0.016 fatalities per 1,000 mile-years (0.008 public fatalities per 1,000 mile-years).

It should be noted that during this 14½-year period, 36 (50%) of the total 72 fatalities and 161 (59%) of the total 274 of those injured were employees of the operating company.

U.S. Natural Gas Transmission Lines - July 1984 through 2006

In June 1984, the DOT changed the criteria for reporting natural gas releases. The most significant change was that in general, leaks causing less than \$50,000 property damage no longer required reporting to the DOT. The criteria for natural gas releases to be reported to the DOT from July 1984 through the present were as follows:

- Events which involved a release of gas from a pipeline, or of liquefied natural gas (LNG) or gas from an LNG facility, which caused: (a) a fatality, or personal injury

necessitating inpatient hospitalization; or (b) estimated property damage, including costs of gas lost by the operator, or others, or both, of \$50,000 or more.

- An event which resulted in an emergency shut-down of an LNG facility.
- An event that was significant, in the judgment of the operator, even though it did not meet the criteria above.

Since the reporting threshold is now significantly greater than the prior \$5,000 reporting criteria, a significant decrease in the resulting reportable incident rate resulted. The frequency of reportable injuries and fatalities also decreased. These data are summarized below for the 21 period from January 1, 1986 through December 31, 2006. (The average length of U. S. transmission lines during the 20-year period through 2005 was 295,539 miles; mileage is not yet available for 2006.)

- Reportable Unintentional Releases - 0.31 incidents per 1,000 mile-years
- Reportable Injuries - 0.040 injuries per 1,000 mile-years
- Fatalities - 0.010 fatalities per 1,000 mile-years

In 2002, the DOT changed their reporting forms. At this time, operators were required to begin reporting additional data for each reportable release. These changes were significant. Some of the additional reporting fields included the reporting of fires and explosions, which were not required to be identified previously. (These data will be presented in the following section.)

For the most recent five year period that national data is available (January 2002 through December 2006), there were a total of 623 reportable incidents from natural gas transmission pipelines, including 27 reportable injuries, and 5 fatalities. The average property damage was nearly \$750,000 per incident. The average annual transmission pipeline mileage was 302,250 miles for this five year period. Using these data, the frequency of reportable incidents during this most recent five year period was up slightly when compared to the 21 year period presented above - 0.41 incidents per 1,000 mile-years for 2002 through 2006 versus 0.31 incidents per 1,000 mile-years for 1986 through 2006. The injury and fatality rates were 0.018 and 0.003 incidents per 1,000 mile-years respectively, down significantly.

U.S. Hazardous Liquid Pipelines - 1984 through 1998

The criteria for hazardous liquid pipeline incidents to be reported to the DOT for inclusion in this data set were as follows:

- Explosion or fire not intentionally set by the operator;

- Loss of more than 50 barrels (2,100 gallons) of liquid or carbon dioxide;
- Escape to the atmosphere of more than five barrels per day of highly volatile liquid;
- Death of any person;
- Bodily harm to any person resulting in loss of consciousness, necessity to carry the person from the scene, or disability which prevents the discharge of normal duties or the pursuit of normal activities beyond the day of the accident; and/or
- Estimated property damage to the property of the operator, or others, or both, exceeding \$5,000, prior to June 1994. After June 1994, this criteria was changed to \$50,000, including the cost of clean-up, recovery, and the value of any lost product.

The data for this period are summarized below:

- Reportable Unintentional Releases - 1.29 incidents per 1,000 mile-years
- Reportable Injuries - 0.076 injuries per 1,000 mile-years
- Fatalities - 0.015 fatalities per 1,000 mile-years

It should be noted that the 1994 Annual Report on Pipeline Safety excluded 1,851 individuals who were injured with minor burns and vapor inhalation from the failure and ignition of seven hazardous liquid pipelines during the San Jacinto River floods in mid-October, 1994, near Houston, Texas. These incidents were caused by severe flooding in the area. These injuries are not included in the injury rate shown above.

It is interesting to note that the incident rate for hazardous liquid pipeline releases (prior to 1994) was essentially the same as those for reportable U.S. natural gas transmission and gathering lines from 1970 through June 1984, which had a similar \$5,000 property damage reporting requirement.

Regulated California Hazardous Liquid Pipelines - 1981 through 1990

This study, undertaken by the California State Fire Marshal, Pipeline Safety Division, included all regulated California interstate and intrastate hazardous liquid pipelines. It included approximately 7,800 miles of pipeline data, over a ten year period (1981 through 1990). The systems included in this study had complete release records. The major difference for this study, as compared to ones discussed previously, is that all releases, regardless of size, cause, extent of property damage, or extent of injury were included in the study. Also, a complete audit of the pipeline inventory and release data was conducted. As a result, the incident rates resulting from this study were higher than

presented in other studies, which only included reported releases fitting a relatively narrow set of criteria. A summary of these results is included below.

- Unintentional Releases - 7.08 incidents per 1,000 mile-years
- Injuries - 0.685 injuries per 1,000 mile-years
- Fatalities - 0.042 fatalities per 1,000 mile-years

Summary of Historical Pipeline Consequence Data

In the following table, the available pipeline release data have been summarized.

Table 4.1.2-3 Pipeline Release Consequences by Data Source

Consequence	U.S. Natural Gas Transmission 1970 to June 1984	U.S. Natural Gas Transmission July 1984 thru 2006	U.S. Natural Gas Transmission 2002 thru 2006	U.S. Hazardous Liquid - 1984 thru 1998	California Hazardous Liquid - 1981 thru 1990
Reportable Incidents	1.30 (\$5,000 criteria)	0.31 (\$50,000 criteria)	0.41 (\$50,000 criteria)	1.29 (\$5,000 criteria)	7.08 (all incidents, regardless of size and value of property damage)
Injuries regardless of severity	N/A	N/A	N/A	N/A	0.685
Injury requiring hospitalization	0.096	0.040	0.018	N/A	N/A
Injuries requiring hospitalization, causing loss of consciousness, or preventing discharge of normal duties day following the incident	N/A	N/A	N/A	0.076	N/A
Fatalities	0.016	0.010	0.003	0.015	0.042

In the table above, the data are presented in units of incidents per 1,000 mile-years. There were three fatalities in the 10-year California study. With the relatively small data sample, the resulting fatality rate was significantly affected.

4.1.3 Qualitative Risk Assessment

Anticipated Frequency of Unintentional Releases

Using the data compiled in the previous section, the anticipated frequencies of unintentional releases by various causes have been estimated. These data, for the proposed pipeline are shown in Table 4.1.3-1 below. These data also include anticipated releases from the regulator stations and other appurtenances, which are also under USDOT jurisdiction and are subject to the pipeline incident reporting requirements.

Table 4.1.3-1 Anticipated Frequency of Unintentional Releases, Proposed 11.0 Mile, 24-inch Diameter Pipeline

Incident Cause	Incident Rate (Unintentional releases per 1,000 mile years)	Anticipated Number of Incidents Per Year	Likelihood of Annual Occurrence
External Corrosion	1.00	0.0110	1 in 91
Internal Corrosion	0.20	0.0022	1 in 455
3 rd Party - Damage	0.40	0.0044	1 in 227
Human Operating Error	0.10	0.0011	1 in 909
Design Flaw	0.03	0.0003	1 in 3,030
Equipment Malfunction	0.40	0.0044	1 in 227
Maintenance	0.07	0.0008	1 in 1,299
Weld Failure	0.30	0.0033	1 in 303
Other	0.50	0.0055	1 in 182
Total, All Releases, Regardless of Spill Volume	3.00	0.0330	1 in 30
USDOT Reportable Gas Releases - 1970 thru June 1984 criteria (>\$5,000 damage)	1.30	0.0143	1 in 70
USDOT Reportable Gas Releases - Current Criteria (>\$50,000 damage)	0.41	0.0045	1 in 222

Anticipated Frequency of Injuries and Fatalities

Most unintentional natural gas releases are relatively small and do not cause personal injuries or death. In this section, the likelihood of human injuries and deaths will be

estimated using historical data. Later in this document, the human life impacts will be evaluated using a probabilistic approach.

As noted earlier, the primary natural gas component is methane, which is not toxic. Although methane presents a slight inhalation hazard, the primary risk to humans is posed by fire or explosion. A fire could result from a natural gas release with two conditions present. First, a volume of natural gas must be present within the combustible mixture range (5% to 15% methane in air). Second, a source of ignition must be present with sufficient heat to ignite the air/natural gas mixture (1,000°F). In order for an explosion to occur, a third condition must be present - the natural gas vapor cloud must be confined, at least to some degree.

It is difficult to estimate the potential extent of human injury because there are so many variables affecting the size of a fire or explosion: rate of vapor cloud formation (controlled primarily by the release rate), size of the vapor cloud within the combustible range (controlled by weather, including wind and temperature, release rate, etc.), concentration of vapors (varying with wind and topographic conditions), degree of vapor cloud confinement, etc. (These actual conditions will be evaluated later, in Section 4.1.4 of this Appendix.)

Based on the historical data presented earlier, the following frequencies for human life consequences are anticipated:

Table 4.1.3-2 Human Life Impacts Based on Historical Data

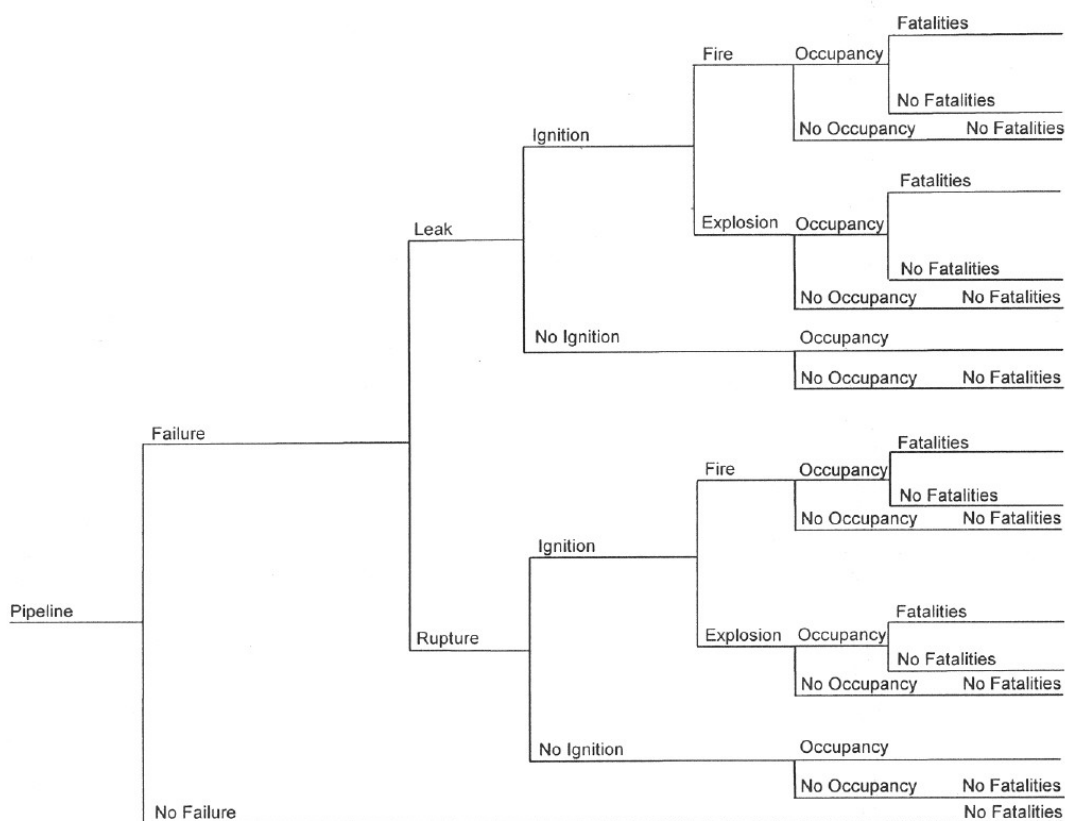
Consequence	Frequency	Annual Number of Events	Return Interval (Years)
Injuries regardless of severity	0.700 incidents per 1,000 mile years	0.0077	130
Injuries requiring hospitalization	0.050 incidents per 1,000 mile years	0.00055	1,818
Fatalities	0.010 fatalities per 1,000 mile years	0.00011	9,091

The anticipated frequencies of injuries and fatalities presented above are useful references. However, they do not facilitate an accurate evaluation of the specific parameters for the proposed pipeline facilities. For example, these summary data do not differentiate between the risks of a relatively benign natural gas pipeline and a liquefied petroleum gas (LPG) pipeline, which is much more likely to result in serious impacts due to fires and explosions. These historical data also do not differentiate

between various population densities. For example, a release in an urban area is likely to cause more significant impacts to humans than a release in a rural, undeveloped area. For the rural setting of the proposed facilities, the values shown above overstate the risk to the public. In the following section, a probabilistic risk assessment will be presented. This analysis will consider the actual open environment, pipe contents, pipe diameter, actual operating conditions and the proximity to the public.

4.1.4 Quantitative Risk Assessment

In this section, a probabilistic pipeline risk assessment will be presented. This analysis considers the actual site population density, as well as the characteristics of the pipe contents in the event of an unintentional release. This analysis was conducted using the following consequence event tree.



Baseline Frequency of Unintentional Releases

For this analysis, a baseline frequency of USDOT reportable unintentional releases of 0.41 incidents per 1,000 mile-years has been used. This is the actual frequency of reportable natural gas transmission pipeline releases from 2002 through 2006.

Conditional Consequence Probabilities

In order to conduct a probabilistic analysis, the conditional probabilities of each fault tree branch must be established. For example:

- What percentage of pipe failures are relatively small leaks versus full bore ruptures?
- What percentage of vapor clouds resulting from leaks and ruptures are ignited?
- What percentage of ignited vapor clouds burn versus explode?
- And in the event of a fire or explosion, do any serious injuries or fatalities result?

In order to evaluate these conditional probabilities, the actual unintentional release data reported to the Department of Transportation, Office of Pipeline Safety (USDOT) has been evaluated. Unfortunately, the USDOT incident reports prior to January 1, 2002 did not include fields for reporting fires or explosions; these fields were added in 2002. Between January 1, 2002 and December 31, 2006, there were 625 transmission pipeline incidents reported to the USDOT. Eighty-three (13.3%) of the resulting vapor clouds ignited. 58% of the vapor clouds simply burned, while 42% of the vapor clouds exploded; this resulted in forty-eight (48) fires and thirty-seven (35) explosions. In other words, 7.7% of the reported natural gas transmission pipeline incidents resulted in fires while 5.6% resulted in explosions.

480 of the incidents were identified as being released directly from the pipeline, as apposed to other appurtenances (e.g., compressors, regulators, etc.). Of these, 110 (23%) of the pipeline releases were identified as ruptures.

It is interesting to note that between January 1, 2002 and December 31, 2006, fifty (50) of the reported 625 natural gas transmission pipeline incidents occurred in compressor stations; fourteen (14) of these incidents resulted in fires and nine (9) resulted in explosions. Thirty-nine (39) of the reported incidents occurred at meter and/or regulator stations; six (6) of these resulted in fires and one (1) resulted in an explosion.

Table 4.1.4-1 Conditional Probabilities

Parameter	Conditional Consequence Probability	Value - Source
Leak Size	Probability of Release (1-inch diameter hole)	77% - USDOT
	Probability of Rupture (complete, full diameter pipe severance)	23% - USDOT
Ignition	Probability of No-Ignition	87% - USDOT
	Probability of Ignition	13% - USDOT
Fire/Explosion	Probability of Fire Upon Ignition	58% - USDOT
	Probability of Explosion Upon Ignition	42% - USDOT

Table 4.1.4-2 Combined Conditional Probabilities

Consequence	Conditional Release Consequence	Value
Fires	Pipeline Release Resulting in a Fire	$0.77 \times 0.13 \times 0.58 = 5.8\%$
	Pipeline Rupture Resulting in a Fire	$0.23 \times 0.13 \times 0.58 = 1.7\%$
Explosions	Pipeline Release Resulting in an Explosion	$0.77 \times 0.13 \times 0.42 = 4.2\%$
	Pipeline Rupture Resulting in an Explosion	$0.23 \times 0.13 \times 0.42 = 1.3\%$

Release Modeling

In this section, various pipeline release scenarios will be presented. The releases were modeled using CANARY, by Quest, version 4.2 software. For vapor cloud explosion modeling, this software uses the Baker-Strehlow model to determine peak side-on overpressures as a function of distance from a release. The CANARY software also uses a torch fire model to determine heat radiation flux as a function of distance from a release. Literally thousands of possible data combinations could be used to evaluate individual releases. However, in order to make a reasonable determination of likely releases, the following assumptions were used:

Table 4.1.4-3 Release Modeling Input

Parameter	Model Input
Operating Pressure	490 psig (505 psia) for 24-inch diameter, 11.0-mile, transmission pipeline The applicant plans to increase the maximum allowable operating pressure from 412 psig to 490 psig in 2009.
Typical Flow Rate	100 MMSCFD for 24-inch transmission pipeline assumed The actual flow rate will vary considerably, depending on natural gas demands, pressures in other system components, etc. This flow rate is likely toward the upper end of anticipated flow rates.
Modeled Releases	1-inch diameter release Full Bore release
Contents	Methane
Contents Temperature	70° F
Wind Speed	2 meters per second (4.5 mph) for vapor cloud explosion modeling 20 mph for torch fire modeling
Stability Class	D - Pasquill-Gifford atmospheric stability is classified by the letters

Parameter	Model Input
	A through F. Stability can be determined by three main factors: wind speed, solar insulation, and general cloudiness. In general, the most unstable (turbulent) atmosphere is characterized by stability class A. Stability A occurs during strong solar radiation and moderate winds. This combination allows for rapid fluctuations in the air and thus greater mixing of the released gas with time. Stability D is characterized by fully overcast or partial cloud cover during daytime or nighttime, and covers all wind speeds. The atmospheric turbulence is not as great during D conditions, so the gas will not mix as quickly with the surrounding atmosphere. Stability F generally occurs during the early morning hours before sunrise (no solar radiation) and under low winds. This combination allows for an atmosphere which appears calm or still and thus restricts the ability to actively mix with the released gas. A stability classification of "D" is generally considered to represent average conditions.
Relative Humidity	70%
Air and Surface Temperature	72° F
Continuous Release Duration	Two (2) hours The applicant has indicated that the anticipated response time to close the manually operated block valves is one (1) hour during normal work hours and two (2) hours outside normal work hours.
Duration of Normal Flow after Leak Initiation	Two (2) hours
Pipe Length Upstream and Downstream of Break	½ of 5.5 miles (distance between manually operated block valves for 24-inch diameter transmission line)
Release Angle	45° above horizontal
Fuel Reactivity	Low - Most hydrocarbons have medium reactivity, as defined by the Baker-Strehlow method. Low reactivity fluids include methane, natural gas (98+% methane), and carbon monoxide. High reactivity fluids include hydrogen, acetylene, ethylene oxide, and propylene oxide.
Obstacle Density	Low - This parameter describes the general level of obstruction in the area including and surrounding the confined (or semi-confined) volume. Low density occurs in open areas or in areas containing widely spaced obstacles. High density occurs in areas of many obstacles, such as tightly-packed process areas or multi-layered pipe racks.
Flame Expansion	3 D - This parameter defines the number of dimensions available for flame expansion. Open areas are 3-D, and produce the smallest levels of overpressure. 2.5-D expansions are used to describe areas that quickly transition from 2-D to 3-D. Examples include compressor sheds and the volume under elevated fan-type heat exchangers. 2-D expansions occur within areas bounded on top and bottom, such as pipe racks, offshore platforms, and some process units. 1-D expansion may occur within long confined volumes such as hallways or drainage pipes, and produce the highest overpressures.
Reflection Factor	2 - This factor is used to include the effects of ground reflection when an explosion is located near grade. A value of 2 is

Parameter	Model Input
	recommended for ground level explosions.

Explosion Modeling Results

As discussed previously, natural gas generally does not explode, unless the vapor cloud is confined in some manner. The proposed pipeline corridor is surrounded by very open, rural land. As a result, there is insufficient confinement to cause a significant vapor cloud explosion within the atmosphere. However, should natural gas migrate into residences or other structures, the overpressures from an explosion within the confined space would be life threatening.

Vapor cloud explosions from the pipeline corridor have been analyzed. The peak overpressure was only 0.16 psig, due to the open surroundings and lack of confinement. To put this into perspective, this level is 20% below the overpressure required to cause glass breakage in buildings with no injuries to building occupants. This level is far less than the 0.70 psig overpressure required to cause minor damage to residential structures or cause minor injuries; this level is also far less than that required to cause serious injuries or deaths. (See also Table 4.1.1-1 for explosion consequences.) The distance from an open area pipeline release to various overpressure levels are provided below, for each of the modeled releases.

Table 4.1.4-4 Vapor Cloud Explosion Modeling Results

Release	Operating Pressure	Distance from Unintentional Release (feet)		
		0.16 psig Overpressure	0.10 psig Overpressure	0.05 psig Overpressure
24-inch Pipeline Full Bore Release @ 45° above horizon	490 psig	130	211	470
24-inch Pipeline 1-inch Diameter Release @ 45° above horizon	490 psig	16	26	58

Fire Modeling Results

As indicated in the torch fire results table below, for a pipeline rupture, one would expect a radiant heat flux of 3,500 btu/hour-square-foot (second degree skin burns after ten

seconds of exposure, 15% probability of fatality if prolonged exposure) at up to roughly 162 feet from a full bore release from the 24-inch diameter transmission pipeline. The distance from the unintentional release to radiant heat flux values of 1,600 and 440 btu/hour-square foot are anticipated to be 199 feet and 304 feet, respectively.

For the proposed pipeline, the fire impacts that could result in an injury are limited to relatively short distances from the release. Since these distances are small, one would generally expect affected individuals to find shelter or move beyond the impacted distance before they could be fatally injured. In these cases, one would only have to move slightly over 100 feet from the release to avoid potentially serious or fatal injuries. As a result, it is highly probable that affected individuals would avoid serious injuries and fatalities resulting from torch fires, unless they were exposed directly to the flame, which would extend an estimated 30 feet for a full bore rupture.

Table 4.1.4-5 Torch Fire Modeling Results

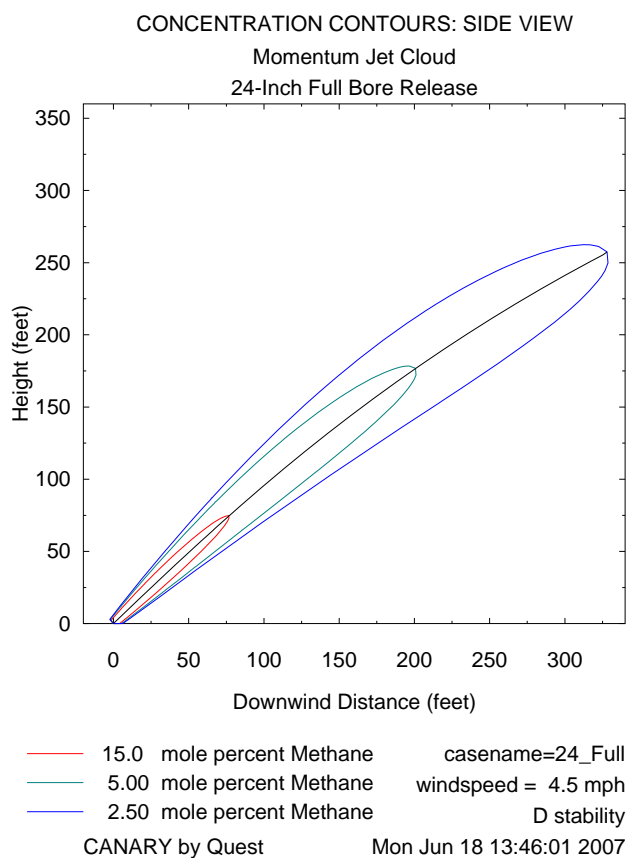
Release	Operating Pressure	Distance from Unintentional Release (feet)		
		3,500 btu/hr-ft ² (11.0 kW/m ²)	1,600 btu/hr-ft ² (11.0 kW/m ²)	440 btu/hr-ft ² (11.0 kW/m ²)
24-inch Pipeline Full Bore Release @ 45°	490 psig	162	199	304
24-inch Pipeline 1-inch Diameter Release @ 45°	490 psig	134	179	440

Note – Radiant heat flux values shown are measured at 6-feet above ground surface.

As discussed previously, flash fires can occur when a vapor cloud is formed, with some portion of the vapor cloud within the combustible range, and the ignition is delayed. (If the ignition is immediate, a torch fire results.) In a flash fire, the portion of the vapor cloud within the combustible range burns quickly. It is assumed that those within the combustible portion of the vapor cloud would likely be seriously injured or killed. Those outside the combustible portion of the vapor cloud would likely be uninjured. In other words, the public would generally be safe if they were too close to the pipeline (over rich mixture, above the upper flammable limit) or beyond the portion of the vapor cloud with concentrations below the lower flammability limit. The results of the flash fire modeling are shown below:

Table 4.1.4-6 Flash Fire Modeling Results

Release	Operating Pressure	Distance from Unintentional Release (feet)	
		Lower Flammability Limit (LFL)	Upper Flammability Limit (UFL)
24-inch Pipeline Full Bore Release @ 45°	490 psig	201	77
24-inch Pipeline 1-inch Diameter Release @ 45°	490 psig	23	8



The figure above presents an elevation of the modeled pipeline rupture at 45° above the horizon. The flammable portion of the vapor cloud is between 5.0 and 15.0 mole percent methane.

Risks to Humans

In analyzing the potential risk to humans, the following assumptions were made:

- Torch Fires versus Flash Fires – The USDOT data does not provide any differentiation regarding the type of fire (torch versus flash). However, since there are a relatively large number of reported explosions in the USDOT database, it is likely that the number of flash fires is limited. There are also few historical flash fires on record (LEES). The analyses of the Proposed Project assumed that 10% of the fires would be flash fires and 90% would be torch fires.
- Residences – In determining the distances from the pipeline to existing and proposed residences, the nearest distance from the pipeline to each residence was used. For individuals outside their homes, the analysis assumed that they would be located near the primary structure. The analysis assumed that in the event that natural gas should migrate into residences, that the occupants would evacuate.
- Flash Fire or Indoor Explosion Exposures to Residences – Should the combustible portion of a vapor cloud migrate to nearby residences before ignition, a flash fire would occur if the ignition were outdoors, or an explosion would occur indoors. The analyses assumed a 100% probability of serious injury or fatality to those exposed to a flash fire. However, those housed within their residences were assumed to be sufficiently protected from a flash fire to prevent serious injury or fatality. The analyses assumed that those protected inside a residence would be able to evacuate safely should the structure catch fire, after the flash fire subsided. The analyses assumed that occupants of these residences would be outside their homes, exposed to flash fire effects, an average of 10% of the time (roughly 17 hours per week). In the event that natural gas were to migrate inside the structure, the analysis assumed a 100% probability of serious injury or fatality. The analyses assumed a 90% probability that occupants would be evacuated by emergency responders, or evacuate the structure on their own once they identified the gas odorant.
- Torch Fire Exposures to Residences – The analyses assumed that residents of all buildings within the 3,500 Btu/hour-square-foot heat flux contour would be exposed to a 0.15 probability of fatality while they are outside their homes. The analyses assumed that individuals would be sheltered from injurious radiant heat impacts while inside their home. The analyses also assumed that those protected inside their residence would be able to evacuate safely should the structure catch fire. The analyses assumed that occupants of these residences would be outside their homes, exposed to torch fire effects, an average of 10% of the time (roughly 17 hours per week).
- Torch Fire Exposures to Vehicle Occupants – Because the size of anticipated fires is small, the analyses assumed that occupants in passing vehicles would be protected from the radiant heat. The analyses assumed that serious injuries and fatalities would only occur to those exposed directly to the flame, which would extend an estimated 30 feet from the release for a full bore rupture.
- Flash Fire Exposure to Vehicle Occupants – There is little actual or experimental data available for natural gas flash fires. Based on a full bore release at 45° above the horizon at the modeled conditions, the flammable concentration of the

vapor cloud would be less than 50-feet wide (measured perpendicular to the release). A vehicle traveling at 40 miles per hour perpendicular to the release would only be within the flammable portion of the vapor cloud for less than one second. Considering the variety of possible release angles, the likely short duration of exposure, and the protection afforded by the vehicle, these analyses assumed that 10% of the occupants of vehicles exposed to the modeled maximum horizontal projection of a flash fire would be seriously injured or killed. It should be noted that 100% casualties are assumed for similar analyses used in the United Kingdom. However, there is evidence that those exposed to flash fires can survive. Although natural gas flash fires are rare, an event occurred on October 1982 which is noteworthy. This event is noted in the Report on a Study of International Pipeline Accidents (HSE 2000). In this case an end cap blew off the end of a natural gas pipeline in Pine Bluff, Arkansas. The ignition of the resulting gas cloud was delayed, until the flammable portion of the cloud reached a nearby welding machine. As stated in the report, “All seven persons at the accident site were engulfed in the flash-fire. The two welder-helpers, who were wearing goggles but not welding helmets, and the two company employees standing atop the ditch at the east and south end were placed in intensive care at a local hospital. Another worker on top the ditch was admitted to the hospital in a serious but stable condition. The two welders, who were under the pipe when the fire erupted and were more sheltered from the fire, were treated and released from the hospital... While none of the workmen were killed, they were not representative of the population as a whole; they were relatively young, fit and wearing working clothes. Children or the elderly (perhaps 50% of the population), or those wearing less protective clothing in a similar fire would probably not have survived.”

- Explosions – The peak overpressures resulting from an atmospheric explosion are anticipated to be below the threshold required to cause serious injuries or fatalities, due to the open surroundings and unconfined nature of a release. However, should natural gas migrate into residences, the overpressures from an explosion within a confined space could be life threatening.

Individual Risks

In the following paragraphs, the impacts (e.g. serious injuries and fatalities) will be evaluated for individuals exposed to a fire or explosion. The lengths of pipeline that could impact the public are summarized below, for each of the identified conditions:

- Flash Fire or Indoor Explosion, Full Bore Release – These impacts could be significant within 201 feet of the pipeline. 4,162 feet of the proposed line would be located within 201 feet of existing and proposed residences (including the proposed Franklin Crossing Subdivision).
- Flash Fire or Indoor Explosion, 1” Diameter Release – These impacts could be significant within 23 feet of the pipeline. None of proposed pipeline would be located within this proximity of existing and proposed residences.

- Torch Fire, Full Bore Release – These impacts could be significant within 162 feet of the pipeline. 3,325 feet of the proposed pipeline would be located within this distance of existing and proposed residences.
- Torch Fire, 1" Diameter Release – These impacts could be significant within 134 feet of the pipeline. 2,825 feet of proposed pipeline would be within this distance of existing and proposed residences.
- Flash Fire, Full Bore Release, Impacts to Vehicular Traffic - Approximately 32,742 lineal feet (6.2 miles) of the proposed pipeline would be within 201 feet of existing roadways. (201 feet is the maximum distance from a release that is expected to cause a significant impact.) An average of traffic speed of 40 mph for determining potential exposure has been assumed. Where available, the numbers of average daily traffic trips for each roadway were taken from Section 4.7 of this document. For roadways where traffic count data was not available, an average of 500 trips per day was assumed. This results in an average exposure probability of 8.59. In other words, an average of 8.6 vehicles would be exposed to the 6.2 miles of pipeline within 201 feet of the pipeline at any one time.

The results of the individual risk analyses are shown below. As indicated, the individual risk of serious injury or fatality is 4.08×10^{-6} . This represents a one in two-hundred-forty-five-thousand (1:245,000) likelihood of a serious injury or fatality. This value which is greater than the generally accepted significance criteria of one in one-million (1:1,000,000). As a result, the individual risk from the proposed project is considered significant.

Table 4.1.4-7 Individual Risk Summary

Release	Baseline Probability of Reportable Release	Affected Pipeline Length (mile)	Probability of Exposure	Conditional Probability of Event	Probability of Serious Injury or Fatality to Exposed Individual	Annual Risk of Individual Serious Injury or Fatality
1-inch Diameter Torch Fire Residences	4.10e-04	0.54	0.10	0.0523	0.15	1.72e-07
1-inch Diameter Flash Fire or Indoor Explosion Residences	4.10e-04	0.00	0.10	0.0058	1.00	0.00e+00
Rupture Torch Fire Residences	4.10e-04	0.63	0.10	0.0156	0.15	6.04e-08
Rupture	4.10e-04	0.79	0.10	0.0017	1.00	5.60e-08

Flash Fire or Indoor Explosion Residences						
1-inch Diameter Outdoor Explosion Residences	4.10e-04	0.00	0.70	0.0420	0.10	0.00e+00
Rupture Outdoor Explosion Residences	4.10e-04	0.00	0.70	0.0126	0.10	0.00e+00
1-inch Diameter Torch Fire Roadways	4.10e-04	N/A	N/A	0.0523	N/A	0.00e-00
1-inch Diameter Flash Fire Roadways	4.10e-04	N/A	N/A	0.0058	N/A	0.00e-00
Rupture Torch Fire Roadways	4.10e-04	N/A	N/A	0.0156	N/A	0.00e-00
Rupture Flash Fire or In-Vehicle Explosion Roadways	4.10e-04	6.20	8.59	0.0017	0.10	3.79e-06
Total						4.08e-06

Anticipated Societal Impacts

Societal risk is the probability that a specified number of people will be affected by a given event. The accepted number of casualties is relatively high for lower probability events and much lower for more probable events. This analysis included the following assumptions:

- Flash Fire, Full Bore Release, Residential Impacts - These impacts are localized. For the modeled release, the maximum width of the vapor cloud within the explosive limit is roughly 30-feet wide, measured perpendicular to the release. As noted earlier, the portion of the vapor cloud within the flammable limit extends only 201-feet from the pipeline. As a result, the analysis assumed that only one structure, housing four individuals, would be affected by each of these events.
- Flash Fire, 1" Diameter Release, Residential Impacts – These impacts are very localized. For the modeled release, the maximum width of the vapor cloud within the explosive limit is less than five feet wide, measured perpendicular to the release. As noted earlier, the portion of the vapor cloud within the flammable

limit extends only 23-feet from the pipeline. As a result, the analysis assumed that only one structure, housing four individuals, would be affected by each of these events.

- Torch Fire, Full Bore Release, Residential Impacts - These impacts are very localized. For the modeled release, the 3,500 btu/hr-ft² isopleth extends less than 100-feet on either side of the release, measured perpendicular to the release. As a result, the analysis assumed that only one structure, housing four individuals, would be affected by each event.
- Torch Fire, 1" Diameter Release, Residential Impacts – These impacts are nearly identical to the full bore release discussed above. As a result, the analysis assumed that only one structure, housing four individuals, would be affected by each event.
- Flash Fire or In-Vehicle Explosion, Full Bore Release, Impacts to Vehicular Traffic - These impacts are localized. For the modeled release, the maximum width of the vapor cloud within the explosive limit is roughly 30-feet wide, measured perpendicular to the release. As noted earlier, the portion of the vapor cloud within the flammable limit extends only 201-feet from the pipeline. As a result, the analysis assumed that only one vehicle, with two occupants, would be affected by each event.

The results of the societal risk analyses are shown below. As indicated, the ratio of site casualties to the societal risk criteria is less than 1.0 for each situation. As a result, the societal risk is not considered significant, using the stated societal risk criteria.

Table 4.1.4-8 Societal Risk Summary

Release	Exposure Probability	Probability of Serious Injury or Fatality to Exposed Individuals	Population Exposed	Number of Site Casualties (SC)	Societal Risk Criteria (SRC)	SC/SRC
1-inch Diameter Torch Fire Residences	1.15e-06	0.15	4	0.60	30	0.02
1-inch Diameter Flash Fire or Indoor Explosion Residences	0.00e-00	1.00	N/A	N/A	N/A	N/A
Rupture Torch Fire Residences	4.03e-07	0.15	4	0.60	40	0.02
Rupture Flash Fire or	5.60e-08	1.00	4	4.00	100	0.04

Indoor Explosion Residences						
1-inch Diameter Outdoor Explosion Residences	0.00e-00	0.10	N/A	N/A	N/A	N/A
Rupture Outdoor Explosion Residences	0.00e-00	0.10	N/A	N/A	N/A	N/A
1-inch Diameter Torch Fire Roadways	0.00e-00	N/A	N/A	N/A	N/A	N/A
1-inch Diameter Flash Fire Roadways	0.00e-00	N/A	N/A	N/A	N/A	N/A
Rupture Torch Fire Roadways	0.00e-00	N/A	N/A	N/A	N/A	N/A
Rupture Flash Fire or In-Vehicle Explosion Roadways	3.79e-05	0.10	2	0.20	5	0.04

Mitigation Measures

HAZ-1a. All pipe to be installed within 200 lineal feet of a roadway or structure intended for habitation (including the proposed Franklin Crossing Subdivision) shall meet the following requirements:

- Line pipe shall be manufactured in the year 1990 or later.
- A 6-inch wide polyethylene marker tape shall be installed approximately 12 to 18-inches below the ground surface, above the center of the pipeline. The marking tape shall be brightly colored and shall be marked with an appropriate warning (e.g., Warning – High Pressure Natural Gas Pipeline).
- The pipe wall thickness shall be at least 0.375-inches.
- The depth of cover shall be at least 48-inches.
- 100% of the circumferential welds shall be radiographically inspected in accordance with American Petroleum Institute (API) Standard 1104, Welding of Pipelines and Related Facilities.

- If the in-line inspection required in mitigation measures HAZ-1b below is not implemented because the pipeline is operated below a hoop stress of 40% SMYS, a close interval cathodic protection survey shall be performed at least every seven years, or the entire portion of line within 200-feet of a roadway or structure shall be included in Applicant's Integrity Management Program.
- The Applicant shall demonstrate to the California State Lands Commission and the Public Utilities Commission that the Emergency Response Plans include measures to isolate pedestrian and vehicular traffic from release locations and the anticipated extent of vapor clouds within the flammable limit.

HAZ-1b. Prior to placing the pipeline system into service, the Applicant shall:

- Submit to the California State Lands Commission (CSLC) and the California Public Utilities Commission (CPUC) an Operation and Maintenance (O&M) manual, prepared in accordance with 49 CFR 192.605. The O&M manual shall address internal and external maintenance inspections of the completed facility, including but not limited to details of integrity testing methods to be applied, corrosion monitoring and testing of the cathodic protection system, and leak monitoring. In addition, the O&M manual shall also include a preventative mitigation measure analysis for the use of automatic shutdown valves per Federal DOT Part 192.935(c) requirements.
- PG&E shall conduct an in-line inspection of the pipeline if the Maximum Allowable Operating Pressure (MAOP) is raised to a pressure that creates a circumferential stress greater than 40% Specified Minimum Yield Strength (SMYS). The in-line inspection tool shall be capable of identifying pipe anomalies caused by internal and external corrosion and other causes of metal loss.
- An Integrity Management Program for High Consequence Area (HCA) portions of the pipeline shall also be prepared in accordance with 49 CFR 192, Subpart O. The Integrity Management Program shall be submitted to the CSLC and CPUC.

Rationale for Mitigation

The societal risks are not considered significant. However, the individual risks identified herein exceed significance thresholds. The significance of these risks is primarily due to the individual risks caused by exposure to possible flash fires resulting from pipeline ruptures, primarily along Franklin Road, where over five miles of roadway are within the hazard footprint. If the anticipated frequency of pipeline ruptures within approximately 200-feet of the roadways and residences were reduced, then the resulting individual risks posed by the Proposed Project would be reduced proportionally. The proposed mitigation measure is intended to minimize the likelihood and consequences of pipeline ruptures. The natural gas pipeline incidents, which were identified as "ruptures" in the USDOT database from 2002 through 2006 have been reviewed. The following points are worth noting:

- 46% of the ruptures were considered longitudinal tears or cracks. Of the components where the manufacturing date was provided, the average date of manufacture was 1955 – roughly 50 years old at the time of failure. Roughly three-quarters of these incidents were caused by third party damage and external corrosion, with the remainder being caused by a variety of factors.
- 50% of the ruptures were considered circumferential separation. For these cases, there was not a predominant cause(s).
- 4% of the ruptures were considered “other”.

Third Party Damage Mitigation Effectiveness

In western Europe, the effectiveness of various forms of third party damage mitigation has been studied (HSE 2001). The findings are summarized below:

- Increased Wall Thickness – For 24-inch diameter pipe, a wall thickness of 0.375-inches or greater was found to reduce the frequency of third party caused unintentional releases by 80%. (The incident rate was 20% of the norm.)
- Increased Depth of Cover – Pipelines with a depth of cover of 48-inches or greater experienced a 30% reduction in third party caused incidents. (The incident rate was 70% of the norm.)
- Supplemental Third Party Protection – Pipelines protected with some form of third party warning device (e.g., marker tape, concrete cap, steel plates, etc.) experienced a reduction in third party caused incidents of 10%. (The incident rate was 90% of the norm.)

By implementing the above measures, the frequency of third party caused incidents may be reduced by 80 to 90%.

External Corrosions Mitigation Effectiveness

Although data is not available to quantify the effectiveness of the external corrosion mitigation measures, the qualitative impacts can be summarized as follows:

- Increased Wall Thickness – Although increased pipe wall thickness does not prevent external corrosion, it allows more time to pass before a leak may result. This increased time period increases the likelihood that the anomaly will be identified by the operator before a release occurs.
- In-Line Inspection – Internal inspections of pipelines using modern techniques can identify external corrosion and other pipe wall anomalies, reducing the likelihood of a release.
- Close Interval Survey – Close interval cathodic protection surveys can identify coating defects and potential metal loss before a release is experienced.

Circumferential Separation

Inspecting 100% of the circumferential welds in accordance with API 1104 will decrease the likelihood of weld defects, which caused a portion of the circumferential separation ruptures noted in the USDOT database.

Residual Impacts

With the proposed mitigation, the individual risk will be reduced by roughly 50%. However, the individual risk will still be approximately 1:500,000 which exceeds individual risk significance thresholds.

It should be noted that there are a significant number of similar natural gas pipelines located in similar, and even heavily urbanized areas. Many of these pipelines pose a greater risk to the public than the proposed line segment. These risks posed by these facilities have been generally accepted as a cost of modern living.

4.1.5 Impacts of Alternatives

The identified alternatives have been analyzed in the same manner that was used to analyze the proposed project. From a public risk standpoint, the two alternatives present slightly different risks, since each route has slightly different lengths of line which could affect the public in the event of a release and subsequent fire and/or explosion. As shown in the table below, the Proposed Project and the two identified alternatives pose essentially the same risk to the public. The level of risk is greater than that considered significant for both of the identified project alternatives.

Table 4.1.5-1 Summary of Alternatives Risk

Project Alternative	Annual Risk of Serious Injury or Fatality	Annual Likelihood of Serious Risk or Fatality
Proposed Project	4.08e-06	1 : 245,000
Franklin 1 Alternative	3.73e-06	1 : 268,000
Franklin 2 Alternative	3.47e-06	1 : 288,000

4.1.6 Cumulative Projects Impact Analysis

Two proposed projects have been considered as they relate to cumulative impacts and public safety: the proposed Franklin Crossing Subdivision Project and PG&E's proposed increase in maximum operating pressure of their Line 108 from 412 psig to 490 psig.

For the Franklin Crossing Subdivision, the potential fire and explosion impacts to occupants of the proposed residences were evaluated; these impacts were included in the analyses presented in sections 4.1.4 and 4.1.5 above. The release modeling presented considered the maximum operating pressure of 490 psig, versus the current 412 psig maximum operating pressure.

References:

California Department of Education (CDE 2007). February 2007. Guidance Protocol for School Site Pipeline Risk Analysis.

California Public Utilities Commission (CPUC 2006). Mitigated Negative Declaration for the Kirby Hills Natural Gas Storage Facility (A. 05-07-018).

Health and Safety Executive (HSE 2000). Report on a Study of International Pipeline Accidents, Contract Research Report 294/2000. United Kingdom.

Health and Safety Executive (HSE 2001). An Assessment of Measures in Use for Gas Pipelines to Mitigate Against Damage Caused by Third Party Activity. Contract Research Report 372/2001. United Kingdom. Mannan, Dr. Sam. Lee's Loss Prevention in the Process Industries. (LEES) Third Edition.

National Transportation Safety Board (NTSB 2002). Pipeline Rupture and Subsequent Fire in Bellingham, Washington, June 10, 1999. Pipeline Accident Report NTSB/PAR-02/02. Washington, DC.

National Transportation Safety Board (NTSB 2003). Natural Gas Pipeline Rupture and Fire Near Carlsbad, New Mexico, August 19, 2000. Pipeline Accident Report NTSB/PAR-03/01. Washington, DC.

Payne, Brian L. et al. EDM Services, Inc. 1993. California Hazardous Liquid Pipeline Risk Assessment, Prepared for California State Fire Marshal, March.

Pacific Gas and Electric Company (PG&E 2007). 2007. Pipeline Extension L-108 Drawing 7051645, Revision 01, sheets 1 through 31.

Quest Consultants, CANARY. (QUEST 2003) CANARY by Quest User's Manual. 2003.

United States Department of Transportation (USDOT), Bureau of Transportation Statistics. Various Years. National Transportation Statistics. Accessed data at <http://ops.dot.gov/stats/IA98.htm> in June 2007.